Hydro Tasmania
the renewable energy business

3 August 2009

Dr John Tamblyn,

Chairman, Australian Energy Market Commission,

PO Box A2449,

Sydney South NSW 1235

By email: submissions@aemc.gov.au

Dear Dr Tamblyn,

Re : **Review of Energy Market Frameworks in light of Climate Change Policies,**

2nd Interim Report

Hydro Tasmania would like to thank the AEMC for the invitation to comment on the material presented in the 2nd Interim Report, which was published as an outcome of the "Review of Energy Market Frameworks in light of Climate Change Policies".

Hydro Tasmania is also a party to three submissions by:

- the National Generators' Forum,
- the Clean Energy Council, and
- a group of Generators comprising AGL Energy Limited, International Power Australia, Loy Yang Marketing Management Company Limited and TRUenergy Propriety Limited, together with Hydro Tasmania.

Unless specifically stated otherwise, our comments are restricted to potential framework weaknesses in the NEM, rather than the WEM or NT arrangements.

Broadly, we believe that the Commission's 2nd Interim report has made significant progress in contributing to developing market understanding of the

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issues related to the critical areas, where the Market Frameworks are likely to be stressed by Climate Change policies.

However, we note that some issues and proposals raised by the AEMC remain in need of considerable work; in our view notably the way in which the best processes can be developed, to ensure that timely and economically efficient augmentation of the transmission system occurs, (both shared network and new grouped connection assets).

The focus of this Hydro Tasmania submission is on:

1. the AEMC's proposed G-TUOS arrangements;
2. the need to address inertia in a timely manner; and
3. an indication of the options for change.

If you require any further information, please contact me on (03) 6230 5775.

Yours sincerely,

David Bowker

Manager Regulatory Affairs

Hydro Tasmania

Hydro Tasmania's Submission on 2nd Interim Report

"Review of Energy Market Frameworks in light of Climate Change Policies"

Submission Information

Submission in response to:

Australian Energy Market Commission
Review of Energy Market Frameworks in light of Climate Change Policies
2nd Interim Report, 30 June 2000

Submission lodged 3 August 2009 via submissions@aemc.com.au

Company Information

Hydro Tasmania is a Government Business Enterprise, owned by the State of Tasmania and is Australia's leading renewable energy business.

The value of Hydro Tasmania's total power system is realised through trading electricity and energy products as a participant in the National Electricity Market with total generating capacity of 2615 MW and assets worth approximately $4.8 billion. Through its Consulting arm, Hydro Tasmania has considerable expertise in the area of power system planning and development.

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"Review of Energy Market Frameworks in light of Climate Change Policies"

Executive Summary

The Hydro Tasmania submission argues that even if the RIT-T is 'softened' to make it easier to develop customer-funded, augmentation of the shared network, there will in future, be significant network congestion on an ongoing but intermittent basis.

The current G-TUOS proposal is not seen as a solution to this problem. We argue that the alternative of a form of Deep Connection Charges, (DCC) should not be ruled out. This is because many of the difficulties described in Section 3.3.6 of the 2nd Interim Report, in relation to DCC are either overstated or would occur with any form of G-TUOS, which provided a realistic locational signal.

The NERG concept is supported in general, but the many aspects which need to be clarified, are identified.

Finally, the issues of short-term reliability, Marginal Loss Factor variability and inertia are discussed briefly.

1 The RIT-T

We agree that the removal of all intra-regional congestion is un-economic, even if this is restricted to "system normal" conditions. The RIT-T will allow a certain amount of shared network augmentation. This will be justified in terms of benefits to loads, and will be paid for by loads under the existing network pricing arrangements.

However, in spite of the RIT-T, shared network congestion will still occur for three reasons:

- **Evaluation basis** – The RIT – T evaluates congestion on the "central planning" basis of comparing marginal generation cost outcomes, whereas individual participants will value congestion based on potential contract market exposure to market cap prices,

- **Time delays** – There will be significant delay between the first appearance of congestion and the identification of the potential augmentation as a candidate for the RIT-T. Then further delays will occur until the detailed design, planning and construction is completed. This could be a period of years.

- **RIT-T Shortfalls** - Some congestion may be short-lived and just fall below the threshold of the RIT-T. [However, an individual generator could make a valid business decision to fund the gap, in order to provide comfort to their contract traders, who might otherwise be exposed to an inability to back contracts].

2 G-TUOS

The current G-TUOS proposal emerged for the first time in the 2nd issues paper. Whilst we understand that it is an initial attempt to derive a locational signal, we believe that further market consultation is required before the appropriate signal is developed; current G-TUOS is not the answer.

Attachment A to this submission details the reasons why the proposed G-TUOS model should not be implemented, and identifies two other approaches which are preferred.

3 Deep Connection Charges

Section 3.3.6 of the AEMC's 2nd Issues Paper is titled, "Why negotiated financial access is not appropriate". We believe that the arguments presented in Section 3.3.6 are based on a flawed appreciation of the transmission planning process and a failure to appreciate that determining the required network augmentation to incorporate new generation investment is indeed feasible. Assessment of require network augmentation was done routinely by the network planners in the old vertically integrated systems, prior to the market. In fact, the same augmentation cost assessment process would be required in order to determine the G-TUOS charge.

In the case of a specific connection applicant, the advantage (over the G-TUOS scenario) is that the TNSP would be proceeding on the basis of a well defined application, whereas in the case of G-TUOS, the TNSP would need to look forward and make forecasts regarding future network usage, and/or generation technology/location.

Further rebuttal of the 3.3.6 assertions and support for the DCC approach are presented in other submissions, to which Hydro Tasmania is a party.

4 NERG

We believe that in principle, the broad concept of the NERG is a positive for the market and note similar developments in North America, (WREZ) and the SEA process for possible offshore windfarms in the UK. However, several operational details need to be worked out, through a consultation process, so that the best ideas can emerge.

Issues to be developed are:

1. The criteria for identifying candidate NERG zones,
2. The roles of Market Participants in determining which NERGS actually get built,

3. The role (if any) of non-market stakeholders, such as State bodies, in determining which NERGS actually get built,
4. Who decides the level of "overbuild"; who wears the financial risk,
5. The cost-recovery mechanisms, (customer/generator/smearing/cross-region sharing),
6. How NERG interface with the RIT-T,
7. NERG as prescribed or negotiated assets, (in Chapter 6),
8. How environmental and planning processes interface with the NERG concept, (cf the UK's SEA process), and
9. If a broader roll out of NERG (into the shared network) would avoid a potential "NERGs to Nowhere" outcome[1].

5 Materiality of Congestion

To date, there is no well-defined and generally accepted measure for congestion materiality. As indicated above, a central planner and individual generator may assign quite different values to short-term congestion.

The assertion that transmission congestion is not-material is not supported by many Generators with potential trading risk/losses, especially those south of the Murray node..

Consequently, in addition to an investment timeframe locational signal, we believe that the market would benefit from an agreed method to manage shared network congestion in the dispatch timeframe, eg some form of CSP/CSC scheme[2].

We have a view that:

- ultimately a well-defined universal congestion management algorithm is better than a case by case application, (in terms of administrative overheads)[3],
- initial administrative allocation of intra-regional congestion residues is no more contentious than allocation of G-TUOS zone boundaries, [auctions require prescience regarding future value],

[1] That is, if NERG are developed without consideration of downstream congestion risk, there will be great reluctance by investors to fund NERG augmentations, eg a NERG starting from the Riverland or west of Farrell in Tasmania.

[2] Noting that the "Congestion Management Without Rights" model is perhaps a good starting point. See power point presentation from AGL, IPA, LYMMCo, Flinders Power and TRUenergy located at: http://www.aemc.gov.au/Media/docs/International%20Power,%20AGL,%20TRUenergy,%20Flinders%20Power,%20Loy%20Yang%20submission%204%20April%202008-6fd45aa2-5e10-4485-8f46-94244b4064f0-0.pdf

[3] Noting that if congestion is some NEM regions is non-material, then a universal CSP/CSC scheme will have no material impact on settlement in those regions, but will define the future treatment if congestion emerges later, thus providing a stable policy environment.

- charging new entrants a reasonable shared network augmentation costs, in return for allocation of incremental congestion residues, is not a "barrier to entry", and
- extension of the NERG principles to the shared network (50% hurdle and optimal lumpy transmission augmentation) is not only useful but essential to avoid "NERGs to nowhere". [requires intra-regional congestion residue allocation, to avoid free-riders].

However, we accept that we all need to work through the options for developing a good model for transmission investment, in a spirit of searching for the best possible market design to further the market objective.

As noted previously, Hydro Tasmania is a party to a lengthy submission by a group of Generators comprising AGL Energy Limited, International Power Australia, Loy Yang Marketing Management Company Limited and TRUenergy Propriety Limited, together with Hydro Tasmania. We urge the Commission not to dismiss the concerns of this significant group of generators in relation to transmission congestion and investment issues.

6 Short-term Reliability

We are concerned in relation to the proposed Load Shedding Management, (LSM) process. The interaction between the operation and financial incentives of LSM, conventional DSM, load provision of FCAS and Jurisdictional arrangements for mandated load shedding and/or generation/transmission inter tripping, needs to be carefully considered.

Since Hydro Tasmania is a party to submissions others, we do not repeat the points made in those submissions, in relation to generation capacity in the short term.

7 Managing Static Loss Factor Variations

We note the concerns in relation to large variations in static marginal loss factors, (MLF). However apart from changes to network configuration and assets, MLF can vary due to tidal network usage.

Given that the G-TUOS scheme is revenue neutral, we are uncertain as to the source of intra-regional residue funding, which is proposed in the 2nd Interim report, (pg 41) as a risk management tool for MLF variability. Given that large volumes of traded energy are involved, the funding would potentially be material. Un-hedgeable uplift payments are undesirable.

8 Inertia

We note the AEMC's comments in the 2nd Issues Paper on inertia and caution that although the existing market frameworks do in principle, provide a mechanism for dealing with this issue, it is not apparent that it will be dealt with in a timely manner.

It may well be that the current NEM treatment of inertia in relation to FCAS procurement may limit the ability to develop the wind resources of Tasmania and South Australia.

We support the comments made by Transend Networks in relation to inertia, in its submission to the 2nd Issues Paper.

Attachment A - AEMC's G-TUOS Proposal

SUMMARY

The AEMC's G-TUOS proposal is driven by the need to create an efficient locational price signal for new and retiring generation investment in the NEM.

Each NEM region would be divided in to G-TUOS zones, which would be charged positive or negative fixed transmission charges, depending on the level of **projected** transmission congestion.

There are significant objections to the G-TUOS proposal; both from a theoretical and practical perspective. Key objections are that no shared transmission is augmented, future costs are uncertain and existing generators cannot respond to the locational price signal.

Background to G-TUOS proposal

As part of its current "Review of the Market Frameworks in the Light of Climate Change Policies", the AEMC seconded Darryl Biggar, an economist with the ACCC, to review transmission investment and cost recovery principles and practice.

On 23 April 2009 Dr Biggar produced a paper, "Framework for Analysing Transmission Policies". In this work, it was noted that whereas traditionally coordination between generation and transmission investment was achieved through vertical integration, in a liberalised electricity market, such as the NEM, where generation and transmission are under separate ownership, that coordination must take place through other mechanisms – such as price signalling, contractual arrangements, and explicit coordination rules and processes, (pg 5)

Two forms of spatial differentiated price signals were identified:

(a) short-run spot-market pricing &

(b) long-term locational signalling, through fixed transmission charges.

The principles enunciated in the Biggar paper were:

1. The fixed transmission charges at the same location should be different for different generators and loads reflecting the different possible patterns of congestion on the network at the time that generator or load is making use of the transmission system;
2. The total locational differentiation in charges between two locations should exceed the "incremental cost" of upgrading the transmission network to provide services between those two locations and should be less than the "stand alone" cost of upgrading the transmission network to provide services between those two locations.
3. The transmission charges (both from short-run locational price differentials and from locational differentiation in the fixed transmission charges) should be stable over time, in order to facilitate sunk, complementary, location-specific investment by generators and loads.

(emphasis added).

The G-TUOS Proposal

In response to the Biggar paper, in the Second Interim Report, the AEMC proposed G-TUOS arrangements to deliver a long-term loctional pricing signal.

Several aspects of the G-TUOS proposal remain undefined – in fact, thankfully, the whole concept is regarded as a draft. However, the broad principles appear to be:

- Each NEM region is divided into several zones, to represent different levels of potential congestion – [For G-TUOS to have any effect, there must be more than 1 zone per NEM region. The ANTS[4] zones have been suggested as the basis for G-TUOS pricing, but this leads to a problem, since Tasmania constitutes a single ANTS zone.]
- Over each NEM region, the G-TUOS measure would be revenue neutral, but some zones would receive payment from the TNSP and others would pay (if they were assessed to be in a potentially congested zone). Customer TUOS would be unaffected.
- The charges would reflect the change in the net present value of future network investment due to the projected change in generation capacity at each location, based on the forward-looking, long run incremental network costs[5]. However, some scaling would be needed to achieve the zero-sum outcome. The charge would be on an installed capacity basis, rather than on generated energy.
- The charges would be reviewed annually on the basis of a revised assessment of future generation investment. [an alternative is a fixed long-term annual charge, based on a 20-year look-ahead at projected generation investment].

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[4] Annual National Transmission Statement, see http://www.aemo.com.au/planning/040-0053.pdf for definition of the 17 ANTS zones.

[5] Note that in order to determine the cost of the required network augmentation, both an accurate assessment of future generation locations and the capital cost of the financially optimal augmentation project would need to be determined. The first of these is problematic and open to challenge, based as it is on imperfect information. The second is precisely the task required in order to implement a "deep connection charge" model, (DCC). It seems strange that this transmission planning process is considered unfeasible in Section 3.3.6 of the 2nd interim paper in relation to DCC but is clearly require for G-TUOS to provide a meaningful locational signal.

Why G-TUOS Wouldn't Work

The key objections to the G-TUOS proposal are that no shared transmission is augmented, future costs are uncertain and existing generators cannot respond to the locational price signal.

Objection	Consequence of feature
1. Because the proposal generates no net revenue, it cannot lead to any actual shared network augmentation. Intra-regional congestion remains.	Existing generators will not only see an increase in fixed transmission charges, they will also have to live with constraints – no process to clear these.
2. The measure relies on modelling of future generation investment – notoriously difficult. In practice, it would lead to significant uncertainty in future costs, an un-bankable situation for a generation investor.	Since all (including negatively priced zones) would face the risk of future cost increases, this would feed through to the contract market and ultimately to customer prices.
3. The proposed ANTS zones are too coarse a mesh – discrimination at voltage level is essential. To provide any sort of accurate locational price signal, significantly more zones will be required.	This becomes administratively complex, with much contention regarding zone boundaries, criteria for boundary re-alignment and the administrative overhead of boundary reviews.
4. The magnitude of the signal will need to be large if it is to act as an effective deterrent to location in congested areas,	See Biggar's principle #2. This is a large cost impost on an incumbent generator, who is unable to re-locate in response to the price signal.
5. Interaction with the Regulatory Investment Test for Transmission, (RIT-T) is uncertain. [The RIT-T justifies reliable efficient-cost supply to **loads**, not generator access].	If the RIT-T is softened, so that all intra-regional constraints are built-out, then G-TUOS would be zero everywhere. However, if not, then the potential exists for some of the generator's constraint to be relieved by a regulated investment. Will off-set/refunds be allowed?

Objection	Consequence of feature
6. No discrimination between generation types. Plant that can usually limit output at peak times should be treated differently from peaking plant. (cf Biggar principle #1).	Different types of generation use the network differently, costs should be different for different usage at the same connection point.
7. The scenario of retiring an old inefficient plant to make way for a new efficient one, is possible but unlikely. Only rarely will the existing transmission be appropriately located and sized for new generation.	In practice, old plant will continue until the carbon costs rise significantly. The RET/CPRS policy will deal with retirement rate. New plant will mostly locate for energy source reasons.
8. This is a regulatory solution, it assumes that the central planners have an accurate view of future generation investment and does not envisage any generator funded augmentations of the shared network.	Biggar-2 "A determination of the socially-optimal transmission expansion path depends on access to information on future generation technologies and opportunities which is not necessarily information available to the transmission planner", (pg 28) Assigning costs on the basis of a <u>predicted future network usage</u> is risky for generators
9. It may be inherently oscillatory, ie as investors respond to the positive revenue stream and flock to an uncongested location, it then becomes congested – is this stable?	Much depends on the timing of reviews and investment commitments. If you locate in a cheap area, will your costs increase later as congestion occurs? [cf MLFs].

Way Forward

If the AEMC accepts some or all of the above objections, then what is the way forward?

Three alternatives are envisaged:

1. Modify the G-TUOS proposal,
2. Build-out all or most intra-regional congestion,
3. Develop some form of deep connection charges.

Aspects of the G-TUOS proposal which could be modified are:

Possible Change	Implication of Change
Exclusion/Inclusion of existing generators who can't respond to the locational signal, (except by shutting down).	Whilst generating a locational signal to a sunk investment is pointless, the belief persists that to exclude existing generators from the G-TUOS arrangements would constitute a "barrier to entry".
They accept that 1 zone for TAS does nothing, so would have to change their approach (or exclude Tasmania).	However, this opens the door to claims for other adjustments to ANTS zones, eg NSW & QLD. Contentious annual review?
Annual charge leads to future net-revenue at risk, (cost uncertainty). This may shift AEMC to basing G-TUOS on longer-term, fixed prices.	This mutes the responsiveness of the locational signal but also locks-in a long-term modelling errors in projected generation & transmission needs. Either way, G-TUOS is a poor long-term investment signal
May change to net positive income over a NEM region to permit some funding of shared network augmentation.	Leads to generator funding without any certainty about specific access improvement or control over where the money is spent. Starts to approach "deep connection charges" if G-TUOS for new entry only.

References

1	AEMC review	http://www.aemc.gov.au/Market-Reviews/Open/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html
2	Draft Biggar paper (Biggar-1)	http://www.aemc.gov.au/Media/docs/Biggar%20Draft%20Report-1d4b0397-5b0a-4c9a-a026-d8babcb7bdca-0.pdf
3	Hydro Tasmania's comments on Biggar paper	http://www.aemc.gov.au/Media/docs/Public%20Forum%20-%20Melbourne%20-%20Biggar%20Paper%20-%20Hydro%20Tasmania-67700977-6ecb-4bb1-8daa-12f41fbef1ce-0.pdf
4	Revised Biggar Paper (Biggar-2)	http://www.aemc.gov.au/Media/docs/Framework%20for%20Analysing%20Transmission%20Policies%20in%20the%20Light%20of%20Climate%20Change%20Final%20Report%20(Dr%20Darryl%20Biggar)-4803ab59-1e2a-4a10-84ed-66b07f4318ad-0.PDF
5	AEMC-1 description of G-TUOS	Chapter 3 of http://www.aemc.gov.au/Media/docs/Second%20Interim%20Report-5b4f2d74-8c01-4546-8805-c992d196e35f-0.PDF